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# Some Practical Aspects Of Reservoir Management

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## Abstract

The potential benefits of reservoir management are beginning to be recognized, and many operators are becoming interested in cost-effectively applying reservoir management concepts. The U.S. Department of Energy (DOE) has implemented a Reservoir Management Demonstration Program of cooperative research and development projects to encourage operators with limited resources and experience to learn, implement, and disperse sound reservoir management techniques.

From work accomplished in the context of these projects, several characteristics of reservoir management have emerged. The reservoir management process is cyclic and consists primarily of the formulation, implementation, and monitoring of a reservoir management plan generally designed to maximize the profitability of a reservoir. Success in developing an appropriate reservoir management plan requires a knowledge of (1) the reservoir system, including rocks, fluids, wellbores, and surface facilities; (2) the technologies available to describe, analyze, and exploit the reservoir; and (3) the reservoir management business environment. Monitoring activities include maintaining an awareness of changes in various aspects of reservoir performance, technology, and the business environment. Such changes trigger the need for reevaluation and/or revision of reservoir management plans.

Two projects in progress in the DOE program illustrate the diversity of situations suited for interdisciplinary efforts in developing reservoir management plans. One project, the East Randolph Field Project, is in a small, newly discovered oil reservoir in the sandstones of the Cambrian Rose Run Formation of eastern Ohio. The other, the Citronelle Field Project, is in a large mature waterflood in sandstones of the Cretaceous Rodessa Formation in south Alabama. The contrasting contexts of these projects provides a proving ground to gain insight into the general procedures for formulating reservoir management plans.

## Introduction

Reservoir management, sometimes referred to as asset management in the context of petroleum reservoirs, has become recognized as an important facet of petroleum production operations in recent years. It is probably not purely coincidence that this increased recognition and interest corresponds to the period of prolonged downturn in petroleum economics that began in the early to mid 1980s and has resulted in significantly lower profit margins. Numerous papers and even books[1] have been written on the subject of reservoir management, but it is still touted as a facet of petroleum production where substantial improvements and advances could be made. In the literature, reservoir management is often treated from an idealistic perspective, focusing on major producers employing high-technology solutions to improve production from large reservoirs. Partly for this reason, reservoir management is still considered an unfamiliar and risky business by many small, independent operators and operators of smaller reservoirs.

Recognizing the relatively widespread lack of understanding of reservoir management, the U.S. Department of Energy (DOE) has implemented a Reservoir Management Demonstration Program to encourage operators with limited resources and experience to learn, implement, and disperse sound reservoir management techniques through cooperative research and development projects. Through BDM-Oklahoma (management and operating contractor for DOE's National Oil Program), DOE has initiated two such projects illustrating the diversity of situations suited for interdisciplinary reservoir management efforts. One project is in a small, newly discovered field in a mature area, and the other is in a large mature waterflood. Project teams are made up of experienced engineers, geoscientists, and other professionals representing BDM-Oklahoma, local operators, service companies, research organizations, state surveys, etc.

The primary objective of this paper is to unravel some of the mystique that surrounds the subject of reservoir management and increase its potential application by:

- Creating a common ground for discussion and communication about reservoir management
- Identifying the primary components of reservoir management
- Presenting a logical approach to reservoir management
- Underscoring the potential of reservoir management to increase profitability and increase or sustain production
- Reviewing the application of reservoir management techniques in case-study examples from DOE's Reservoir Management Demonstration Program

To achieve this end, we have drawn on numerous sources: (1) the extensive literature on the subject of reservoir management, as well as conversations with persons recognized as experts in the field, (2) observed progress of projects being conducted in DOE's Reservoir Management Demonstration Program, and (3) our first-hand experience with industry projects performed in the context of major and independent oil companies.

## What Is Reservoir Management?

Just as there are many publications on the subject, so are there many definitions of reservoir management to accompany them. In 1991, Thakur[2] defined reservoir management as the "judicious use of available resources to maximize economic recovery" Cole et al.[3] went on to specify that "resources" in the above definition include people, equipment, technology, and money. Other definitions, such as that offered by Wiggins and Startzman[4] in 1990 (i.e., reservoir management is "application of state-of-the-art technology to a known reservoir system within a given management environment"), take a slightly different perspective. Most such definitions, however, revolve around identification of the components of reservoir management much as if we were to define an automobile as consisting of engine, wheels, steering mechanism, etc.

Nearly all discussions of reservoir management agree on the following as general characteristics of reservoir management:

- It requires and makes use of resources.
- It is continuous and long-term, over the life of a reservoir.
- It concentrates on economic optimization.

From this, we might surmise that the main activity of reservoir management is a sequence of resource-deployment decisions made to maintain optimum economic recovery of petroleum.

## The Plan as the Central Concept in Reservoir Management

The above definitions are all valuable in that they serve to enlighten us to the important considerations that are critical to reservoir management activities, but taking a slightly different approach may help us grasp the subject more completely.

It would be safe to conclude that every reservoir being operated today, like every business being operated today, is being managed. Some are managed well, and some are without question poorly managed. We can think of well and poorly managed reservoirs and businesses as those that are and are not realizing their maximum potential, respectively. Every operator is taking some kind of approach, that is, every operator has some kind of philosophy, guidelines, or plan that is used to guide interaction with the reservoir. Formulating these guidelines and following them is the real essence of reservoir management[5]. The spectrum of possible approaches, strategies, or plans to employ, however, is extremely wide.

**The Spectrum of Reservoir Management Plans.** Some plans are very simply conceived or literally just assumed. Such a simple and straightforward approach could amount to a stark "produce the reservoir until the total cost of production becomes greater than the revenue obtained, then quit." In this sense, "quit" implies either selling the property to an organization with lower overhead costs that can continue to operate the reservoir at a profit or simply abandoning the reservoir.

The opposite extreme might be a case in which all the latest improved oil recovery technologies are periodically screened and selected technologies are carefully applied in the context of a complete and detailed 3-D description of the physical and chemical aspects of the subsurface reservoir in an attempt to retrieve substantial dollar amounts of oil in return. Intermediate between the extremes are plans that consist of informal guidelines that may or may not be regularly reviewed for appropriateness.

Realizing that there is a spectrum of possible approaches raises some obvious questions. Is either of the extreme approaches ever the correct one to apply? It is reasonable to suppose that there is some optimum reservoir management approach for any given reservoir, but how can we match all the myriads of possible intermediate approaches to appropriate reservoirs? The correct answer is probably "it depends on how well we know (1) the reservoir and its facilities, (2) the availability and use of state-of-the-art technologies, (3) the general business environment, and (4) our own company." Reservoir management might well be thought of as the decision-making process that matches the approach or plan to the reservoir at hand.

***Consequences of Mismatch.*** It is very easy to see that if we don't pay close attention to developing reservoir management plans or guidelines, we will probably get a poor match between the approach implemented and the reservoir's needs. The most likely consequence of a poor match is a less-than-optimum economic performance. Interestingly, poor economic performance can occur in several ways:

- A company may invest hard-earned capital in a reservoir management project, perhaps more than the organization could reasonably afford to risk, and then not only does the scheme not make a return, it loses the investment.
- An implemented reservoir management project is moderately successful, but not as successful as was predicted and

other project investments that could have been selected would have done much better.

- An implemented reservoir management project makes money, perhaps just as predicted by the reservoir management plan. After producing the reservoir or field to economic limits, it is sold and another operator comes into the picture only to make a windfall from enhanced production.
- The reservoir makes money to the economic limit under the implemented scheme and is then abandoned or sold to an operator with lower overhead who continues under the same approach. Only the reservoir knows about the millions of dollars in additional revenues that could have been obtained if only a different approach had been employed, a simple and feasible approach that would have recovered untold amounts of oil above and beyond actual recovery.

***Reservoir Management's Unrealized Potential.*** There is a marked tendency, particularly among smaller operators, to take a very conservative or even oversimplified approach to reservoir management. There are some very understandable reasons:

- First and foremost, many operators have an incomplete understanding of the reservoir management concept. Reservoir management is routinely thought of only as a high-tech, high-dollar venture, with no consideration being given to simpler, lower cost technologies and techniques.
- Some operators are not technically experienced. Their staff may include operations geologists and/or engineers, but no technical specialists. Such operators are reluctant to apply technologies they do not fully understand, and consultants and technical specialists associated with service companies are frequently viewed as having a vested interest in selling technology applications that may not be in their client's best interest.
- Reservoirs in advanced stages of maturity are often only marginally profitable at best. This is a consideration that affects operators of all sizes, but it is especially true of smaller operators who are acquiring an ever larger share of the mature U.S. domestic production as reservoirs are divested by larger operators whose overhead is higher. Low profit margins are viewed as adequate justification for not taking action to attempt to improve recovery or profitability.

The net result of these conditions is that reservoir management is viewed as a risk to be avoided by many operators, both large and small. Risk is an important consideration in reservoir management, but the consequence of excessive risk avoidance through lack of applying effective reservoir management frequently is bypassed potential in terms of revenue and increased recovery.

Because of the generally conservative approach that has been taken to reservoir management, tremendous opportunities for increasing production and profitability exist. Many of these opportunities are not necessarily capital intensive, can be implemented very quickly, and can affect profitability very positively in the short term.

## The Reservoir Management Process

Reservoir management is beginning to be recognized as a powerful tool in managing risk and optimizing profitability. The need for a conscious effort in reservoir management is now being recognized, but there is much yet to be learned about the details of reservoir management methodology. Because the reservoir management plan is both fundamental to reservoir management and because it is dynamic (i.e., it can change with time), formulating, implementing, and revising plans is a primary reservoir management process. The sections following discuss the primary components of the reservoir management process, the characteristics of an effective reservoir management plan, and the criteria that indicate a need for plan revision.

The reservoir management process is illustrated schematically in Figure 1. It consists of an iterative procedure involving (1) constructing a plan of scale and scope appropriate to the reservoir, (2) implementing the plan, and (3) monitoring its performance to determine any need for revision. Revision of plans may result in redefinition of scope and or scale to fit changing reservoir, business environment, or technological conditions.

**Components of the Reservoir Management Process.** Progress is being made in recognizing the components of the reservoir management process and understanding the general organizational environment needed for successful reservoir management.

Efficient reservoir management is not just preventive maintenance nor is it just problem solving. It is not just a depletion plan or a development plan or a plan for implementing a given recovery process. Although it may include any of these considerations, it is much more all-inclusive than any of them individually. It is really a comprehensive, integrated strategy for reservoir exploitation, as referred to by Wiggins and Startzman.[4] As discussed previously, Wiggins and Startzman refer to reservoir management as "application of state-of-the-art technology to a known reservoir system within a given management environment." (This does not imply that state-of-the-art technology is high priced or unproved, just the best available, appropriately priced technology.) Their definition is a particularly good one because it encompasses the fundamental components of reservoir management: (1) knowledge of the reservoir and its facilities (i.e., the reservoir system), (2) knowledge of available technologies, and (3) knowledge of the business context under which reservoir management will occur.

***Knowledge of the Reservoir System.*** The reservoir system is composed of subsurface reservoir rock, its contained fluids, all wellbores and downhole equipment, and surface equipment and facilities. The reservoir rock and its contained fluids can be most efficiently addressed in a discussion of reservoir characterization or reservoir description. The effects of man's activities will be addressed under the heading of wellbores and facilities.

*Reservoir Characterization.* The terms "reservoir description" and "reservoir characterization" have been used almost interchangeably, but reservoir description perhaps more aptly connotes data collection from the reservoir itself, whereas reservoir characterization might be thought of as a more comprehensive undertaking employing other information sources (such as analog reservoirs, outcrops, and modern environments) as well as the subsurface reservoir. The end result is a complete conceptual picture or model of the reservoir. Traditionally, the purpose of reservoir characterization has been to quantitatively transfer information on reservoir property distribution in a sufficient degree of detail and accuracy to a numerical simulator. Reasonableness of the reservoir model is then inferred from how well simulator predictions match historical reservoir performance. Once validated, the simulator model can be used to evaluate production for different development options.

A reservoir characterization model is a representation or estimate of reservoir reality. It represents not only the three-dimensional extent or bounds of the reservoir, but the qualitative (presence or absence) and quantitative (magnitude) values of rock, fluid, and other reservoir parameters affecting fluid flow at every location in the volume of the reservoir. The degree of uncertainty associated with placement and magnitude of fluid-flow properties is also an important facet of this model.

In the past, the aim of reservoir characterization generally was to create a single "most probable" representation of the reservoir to be used as input to subsequent decision making, but the need for a small number of more extreme yet reasonably probable representations is now becoming recognized as a useful if not critical addition. This approach allows bracketing the range of reasonably expected recovery and economic outcomes. An important objective of reservoir characterization model construction is to accurately represent and minimize, as far as economically feasible, the uncertainty in our knowledge of reservoir parameters. We can think of the goal of reservoir characterization as the construction of a model or small number of models that will aid in predicting by simulation or other means the outcome or probable range of outcomes of potential projects, processes, or operating plans and procedures in order to evaluate their relative economic merits.

Reservoir characterization data can come from a wide variety of technologies and cover a wide range of scales. Because a single reservoir characterization model or a small number of such representations is the desired result, and because the necessary data are of both engineering and geological origin, the need for close cooperation between geoscientists, engineers, and other professionals (i.e., the members of the reservoir management team) in formulating such models is paramount. This subject has been the topic of much discussion in the literature and will not be dwelt upon here. Let it suffice to say that data from various individual technological sources often suggest a number of nonunique interpretations of reservoir reality. It is the duty of the reservoir management team to understand and use the various technological data types in complementary and supplementary fashions to arrive at the most probable range of possible reservoir realities upon which to base future reservoir performance predictions. This model construction is not a trivial task, and its successful completion requires continual cooperation and interchange of information and ideas among team members. The task cannot be efficiently accomplished (indeed it may not be accomplishable at all!) if geologists and engineers work on the task sequentially and independently.

Reservoir characterization at different levels of detail plays multiple roles in reservoir management. Reservoir characterizations of different scale and/or scope may be required for reservoirs in different stages of development, more mature reservoirs requiring more detailed models for simulator representation. Modeling a variety of scenarios helps to identify variables that will be critical to future performance. Efforts at data collection and understanding can then be focused on the identified critical items. Also, as a reservoir management plan is being built and evaluated for implementation of a project, process, procedure, etc., reservoir characterization models with different focus may be needed at different stages of plan development. For example, a coarse-scale model at the outset may be required to define the potential size of the oil or gas target, but a detailed reservoir characterization model defining small-scale heterogeneities may later be required to form the basis for simulation of project flowstreams and the economics of project application.

*Knowledge of Wellbores, Facilities, and Past Practices.* In addition to a knowledge of the characteristics of the reservoir rocks and natural fluids, an important aspect of reservoir knowledge is familiarity with the production/injection infrastructure. Natural processes in the subsurface can interact with wellbore equipment resulting in problems such as corrosion, scaling, paraffin deposition, etc. Surface processes, such as erosion or flooding can affect wells and facilities. Knowledge of the history of drilling, completion, recompletion, and workover practices employed in field development as well as familiarity with current surface and wellbore facilities is also necessary. Equally important is a knowledge of past production and injection practices.

Encroaching development may certainly affect surface facilities and the use of wellbores, but it is as important to know of alterations in the natural properties of the reservoir that have resulted from past human activities as it is to know the natural characteristics of the reservoir. Human activities in development and depletion of a reservoir can have a profound influence on its basic characteristics and thus on its performance. In some cases, human activities are equivalent to introduction of whole new and often extreme episodes of diagenesis, tectonics, and/or fluid exchange. The nature of these changes is unexpected in many instances and can result in decreased reservoir performance and permanent reservoir damage if not considered. Examples might include situations where stimulation practices have led to communication between reservoir units behind pipe, or where long periods of water injection above formation parting pressure have led to channeling between injection and production wells.

***Knowledge of Available Technologies.*** Successful reservoir management is also dependent on a familiarity with existing and newly developing technologies that are available to characterize reservoirs, improve operational efficiencies, and improve hydrocarbon recovery. This does not mean that a high-tech approach is necessarily the appropriate one to take. It is much more important to be aware of the wide range of technologies available and the economics involved in assessing and implementing those technologies.

A wide range of technological knowledge from that of building conceptual/analog and stochastic reservoir characterization models to construction of models from a variety of traditional and newly developing deterministic data sources is appropriate for addressing the reservoir characterization aspects of reservoir management.

Familiarity with appropriate techniques and technologies for reducing costs and increasing operating efficiencies through optimization of wellbore and facilities equipment and practices including modern stimulation and completion practices will also be critical.

It is also important to be aware of routine applications techniques and new techniques and technologies associated with improved recovery. Secondary techniques include injection of water or gas (immiscible) for pressure maintenance or displacement of hydrocarbons. Advanced secondary recovery techniques include techniques aimed at improving contact with mobile oil such as infill drilling using vertical and horizontal wells and employing polymers for profile modification and mobility control. Enhanced oil recovery techniques include application of processes to recover immobile oil such as microbial, alkaline and alkaline-surfactant-polymer, surfactant, steam, in situ combustion, and miscible and immiscible gas-injection processes.

Maintaining an awareness of appropriate technologies in so many areas is a difficult task, especially for smaller organizations. Membership and participation in professional societies, attendance at their meetings, and review of their publications may help, but it is not realistic to assume that any organization will always have (or should have) the necessary knowledge and experience in all the areas that may be required. A realistic target is to obtain enough of a general (screening level) knowledge of available technologies to know when an expert should be consulted. Numerous professional societies and organizations like the regional offices of the Petroleum Technology Transfer Council can provide contact with the appropriate consulting expertise.

***Knowledge of the Reservoir Management Business Environment.*** The reservoir management business environment includes all factors influencing reservoir management decisions aside from the properties of the reservoir itself (including equipment and facilities) and available technologies. Like technology and the reservoir itself, these factors are dynamic rather than static and must be included in the reservoir management plan.

Reservoir management business environment factors fall into two categories: those that are external to the operator's organization (i.e., those that affect all operators equally) and those that are internal (i.e., their influences are different in different organizations). External factors include considerations such as market economics, taxes, operational regulations, safety and environmental laws and regulations, and social perceptions. Internal factors include the company or organization's attitude toward risk, its acceptable rate of return, its ability to raise and/or commit capital, its objectives, its organizational structure (e.g., interdisciplinary team vs. disciplinary approach to reservoir management), and its ability to commit to execution of long-term plans.[3,4]

The importance of incorporating external and internal reservoir management environment factors into the reservoir management plan cannot be overemphasized. The plan must specify surveillance criteria for these factors as well as those concerning the reservoir and technology. Significant changes in any of these reservoir business environment factors may be just cause for revision of the reservoir management plan.

*Reservoir Management Teams and Team Dynamics.* Thakur and Satter[1] present an excellent discussion on the structure and function of reservoir management teams. Team efforts, performed by multidisciplinary groups sharing common goals, are critical to the success of any reservoir management effort. At project inception, all members should share in developing project goals and objectives and aid in developing and assigning project responsibilities for each team member. A team leader with the multidisciplinary insight and management skills to encourage cooperative participation in these and subsequent project activities is a necessity.

The dynamic interaction of the group comprising the reservoir management team is a strong contributor to the success of the effort. The team leader must be aware that the members of the team may have varying degrees of technical skill and experience in their own disciplines and may have varying experience in working closely with people from other disciplines. The leader must monitor and nurture the daily interaction of team members. To do so the team leader must be aware of individual personality traits and differences in rank, must be aware that certain team members may have commitments to other projects that may compete for their time and dedication at inconsistent and often inconvenient intervals (though management should do everything possible to minimize conflicts in priorities), and must realize that occasional disruptions such as loss or addition of team members may inevitably occur.

**Reservoir Management Plan Characteristics.** Ideally, a reservoir management plan will provide guidelines over the life of the reservoir, or at least up to a time or level of performance specified in the plan as a criterion for reevaluation. Specific objectives of any plan will depend on the necessary scope of the plan, the current stage of reservoir development, and the type and scale of the decisions required (e.g., evaluation of a potential new process implementation, local production and injection optimization, new facilities or equipment technologies, etc.). A comprehensive reservoir management plan initiated at the time of reservoir discovery will assure early collection of native-state reservoir data vital to implementation of advanced recovery processes many years in the reservoir's future. On the other hand, reservoirs in which data collection has been neglected and reservoirs acquired without adequate accompanying data will require a reservoir management plan designed to correct or alleviate the effects of information deficiencies.

A reservoir management plan may specify schedules for implementing technologies, procedures, and reservoir operational activities. The plan may project expected performance by simulation or by other means of all aspects of reservoir performance over the plan's duration (e.g., reservoir wellbore injection and production performance, facilities and equipment usage, environmental and other regulatory compliance, etc.). The plan may specify surveillance and monitoring activities, including data types, collection protocol, database construction, data processing and analysis, and performance variance to be tolerated. The plan may also specify or recommend future plan revisions based on specific criteria such as timing or volume performance of reservoir fluid production or injection. In any event, the plan should be developed so that it is not so rigid as to be inflexible to potential modifications.

**Steps in Reservoir Management Plan Construction.** One of the key objectives in the DOE-sponsored Reservoir Management Demonstration Program to date has been to resolve the sequence of considerations critical to the development of a reservoir management plan. At this point in the program, only the broadest categories have been defined, but it is hoped that subsequent work on a variety of reservoir management projects will enable the procedures to be defined in greater detail with time.

As currently recognized, the primary steps are:

1. Define the target size. (How much oil and/or gas? This step will help to justify the scale of effort.)
2. Locate the recovery target. (Where is it? Is it mobile or immobile, etc.?)
3. Identify the recovery technology to obtain it. (This will include a first pass screening evaluation as well as in-depth investigation of the appropriateness of the technology.)
4. Optimize the implementation of recovery technologies.
5. Optimize operational procedures and technologies.
6. Specify the criteria that will determine the duration of the plan's use.

Many reservoir management projects will not need to consider all of the above steps in detail. For instance, some projects may not address improving recovery and may concentrate on operational optimization. In most stages of plan development listed above, the following considerations should be addressed:

- What is the current level of confidence? Is it acceptable?
- Identify technologies and/or data that may increase that confidence.
- What is the cost-effectiveness of increasing confidence with this new information?
- Weigh the cost against available resources.

**Events Triggering Reservoir Management Plan Revision.** As discussed above, the reservoir management plan itself may specify a condition or set of conditions that indicate the plan should be reevaluated. These criteria may include such items as cumulative volume, relative volume, or rate of production or injection of a specified fluid, passage of a specific period of time, or attaining a particular stage of reservoir development.

At any time, however, performance anomalies of any kind (e.g., production or injection volumes, facilities usage, or regulatory compliance) with respect to plan expectations or predictions may indicate immediate need for plan revision. Ideally, the plan should specify guidelines for tolerance in variation from plan prediction in all critical performance areas; when these tolerances are exceeded the plan should be reviewed and revised.

New information may also be just cause for plan revision at any time. New information may take various forms. It may be new reservoir information, perhaps extracted from data collected under specifications of the current plan, that indicates a conflict with the assumptions that went into formulating the plan. It may be in the form of the introduction of new technologies, ideas, or procedures not available or known at the time the plan was formulated. The critical new information may even be in the form of performance anomalies arising in analogous reservoirs.

Unexpected or unpredicted changes in circumstances or opportunities related to the general or operator-specific business environment may also present cause to reevaluate the reservoir management plan. Examples of factors that may be significant include market economics, new laws and regulations, changes in key personnel, and decisions to buy, sell, or trade reservoirs.

## Case Studies in DOE's Reservoir Management Demonstrations Program

DOE has solicited brief proposals to perform cooperative or shared research in developing and implementing reservoir management plans in pursuit of its goal of improving reservoir management understanding through demonstration and technology transfer. Plan development projects submitted by small business operators of oil reservoirs are selected on the basis of the regional significance of the project, its potential for economic success, the demonstrated degree of problem identification, the availability and quality of data for addressing the key problem(s), the suggested approaches for solution, and the teaming arrangements suggested by the operator.

Once a project is selected, a multidisciplinary team develops a detailed statement of work delineating the scope of the project, as well as its individual subtasks, the schedule of proposed activities, the need for additional data collection, and the makeup, goals, and responsibilities of subteams. Regular meetings of teams and subteams make optimization of the ongoing work possible through modifications of work plans. Teams are composed of experienced engineers, geoscientists, and other professionals representing BDM-Oklahoma, local operators, service companies, research organizations, state surveys, etc. Two reservoir management projects, both in progress, have been selected for discussion here to illustrate aspects of the methodology for reservoir management plan development.

**The East Randolph Field Project.** Since 1993, PEP Drilling Co. and Belden and Blake Corp. have developed this unique but significant oil reservoir in the Cambrian Rose Run Formation in Portage County, Ohio (Figure 2). This new field, one of a few to produce oil from the Rose Run, covers about 1,500 acres, lies at a depth of about 7,200 ft, and contains an average of about 15 ft of net pay in the upper three of five sand zones typically present in the Rose Run (Figure 3). It contains 29 wells and had produced about 390,000 bbl of 42$^{o}$ API oil and more than 800 million cubic ft of gas as of December 1995. Development wells continue to be drilled as the reservoir management project proceeds.

Problems being addressed in this study include evaluation of location for potential development and infill wells, optimum selection (waterflood or gas injection) and implementation of secondary recovery approach, alleviation of paraffin buildup in producing wells, and optimization of hydraulic fracture stimulation techniques. The general nature of these problems was identified by the operator prior to the inception of the project.

The East Randolph Project Team is made up of geoscience, engineering, management, and other professional personnel from both the Belden and Blake and BDM-Oklahoma organizations. At a meeting of the full project team before the project was undertaken, geology, reservoir data, production history, and well history were reviewed and discussed to aid in identifying the areas of major focus for the project. Appropriate personnel and responsibilities were assigned to specific project subtasks. The information obtained was used to develop a formal joint statement of work. Major project tasks identified include (1) a project kickoff meeting, (2) geologic characterization, (3) analysis of reservoir and production data, (4) collection of additional field data, (5) development of reservoir and geologic models for use in reservoir simulation, (6) reservoir simulation, (7) evaluation of production operations, (8) economic analysis, (9) development of a reservoir management strategy or plan, and (10) technology transfer. The kickoff meeting, held early in the project, refined problem definition and prioritization, further developed the task details and personnel assignments, and developed a detailed project schedule.

As a first step toward understanding the large scale fluid distribution and flow properties of the reservoir, geologic (including digital log) data and production data were gathered and assimilated into the GeoGraphix system for analysis. This database was used to develop geologic models or interpretations of the field, which included consideration of lateral reservoir continuity, flow barriers, fractures, and faults as well as overall reservoir volumetrics.

Material balance calculations in conjunction with reservoir volumetrics results obtained so far indicate that the original oil in place (OOIP) for the field is closer to 11 million bbl of oil (MMBO) than the 4.5 MMBO estimated prior to the beginning of the study. Production data and newly obtained PVT data suggest that the upper sand zone in the Rose Run is gas prone. Results from a single-well simulation model support this conclusion also. These findings will have a profound affect on the design of any waterflood or gas repressurization scheme.

A core was obtained from an infill well drilled in June 1996. In addition to sampling for routine core analysis, samples were taken to be used in performing relative permeability and capillary pressure tests. A downhole pressure bomb was run in the well to gather data on permeability and original reservoir pressure.

Data from the infill well will be combined with other available data to simulate a pilot area where the operator is considering the implementation of an improved recovery process (either waterflooding or gas injection). A reservoir management plan will then be developed in which a recommendation of the appropriate recovery process will be detailed.

The progress of this project illustrates the progression from simple to more complex approaches to problem solution. Perhaps more importantly, it emphasizes the importance of investing in the collection of new information to address critical reservoir issues.

**The Citronelle Field Project.** Citronelle field in Mobile County, Alabama (Figure 4), was discovered in 1955. It has since produced 160 MMBO from fluvial sandstones of the Cretaceous Rodessa Formation from depths of more than 10,000 ft. The field contains 468 wells. It was developed and essentially remains today on 40-acre spacing, covering a surface area of 16,400 acres. Early estimates suggested that the field contained about 350 MMBO OOIP. Subsequent field performance suggests that this figure may be conservative. The 800-ft-thick gross pay interval contains at least 42 productive sandstone zones that form over 330 separate reservoirs with highly variable permeability characteristic of fluvial deposition.

Field pressure declined relatively rapidly, leading to the inception of waterflooding in 1961. In early 1995 approximately 15,000 bbl of water were being injected each day into 50 injection wells to produce about 3,600 bbl of oil from about 175 active producers. Cumulative recovery is about 160 MMBO, 120 million bbl of water, and 1.2 billion cubic ft of gas.

The Citronelle Field Reservoir Management Team consists of geoscience, engineering, management and other professionals representing (1) operators of the 341 Tract, East, Southeast, and Northwest Units of the Citronelle field; (2) operators of geologically analogous reservoirs in the area; (3) the Alabama Geological Survey; (4) the State Oil and Gas Board of Alabama; (5) the University of Alabama; (6) BDM-Oklahoma; and (7) a private engineering consultant with a long history of association with the Citronelle Field. Several major reservoir management decisions were made by the team in the very early stages of the project even before the detailed work plan for the reservoir management project was constructed. There was general agreement that a substantial oil target remains in Citronelle field that justifies a reservoir management effort for its recovery. All recognized that, under current operations, the economic limit for the field was approaching within a few years. Discussion focused on achieving a cost-effective approach through careful matching of the limited resources available for commitment to the probability of improving production and/or profitability. The resulting circumscribing of reservoir management activities was, in reality, the beginning of reservoir management plan development.

It was agreed that, rather than considering the entire field, the most economically reasonable approach would be to concentrate on geographic areas where certain significant problems were prevalent. Solution of problems in these areas should have most significant impact on profitability per dollar expended. Methodologies developed in problem identification and solution in the selected areas can be applied later on a field-wide basis. This approach allows the untapped profitability potential of the field to be developed in small incremental steps that are more financially feasible than if the whole field and all of its possible problems were attacked at once.

With this concept as a guideline, a kickoff workshop with the full reservoir management team in attendance was conceived as the logical first step in the project. The objectives of this workshop were to (1) identify and prioritize the problems to be addressed (these can be alternatively viewed as opportunities for improvement), (2) identify and prioritize geographic areas in the field where the critical problems are prominent, (3) review the inventory of data available for problem solution in the areas identified, (4) identify additional data requirements for the project, (5) develop a detailed plan and schedule of project activities based on the results of 1 through 4, (6) assign team personnel responsible for execution of the various tasks defined and delineated in 5, and (7) identify opportunities for technology transfer to other operators.

The most critical issue of a general nature identified at the kickoff workshop was that of waterflood optimization, although consideration of other, possibly more economic, recovery methods was viewed as important also. Other more specific problems, many of which were identified by the operator prior to submission of the project proposal, included drilling and completion/recompletion problems, casing leaks, paraffins, chlorites, scaling, produced fines, and problems associated with hydraulic pumps and the power oil system. Boundary areas (Figure 5) between the Citronelle 341 Tract Unit and the East and Southeast units were identified as areas where the current waterflood has been least efficient in recovering oil reserves. These are areas where no unified effort has been made in the past to optimize injection or production strategies, and they are likely to contain considerable untapped potential.

Other major project tasks as outlined in the work plan include data acquisition and computerization, reservoir characterization, evaluation of drilling and recompletion operations, evaluation of production operations, evaluation of waterflood operations, evaluation of other potential improved recovery methods, assessment of environmental and regulatory issues, economic analyses, final formulation of a reservoir management plan, and transfer of the project methodologies and results to industry.

The long history of Citronelle field has included detailed field-wide geological and engineering studies performed mostly in the mid 1960s in preparation for installing the waterflood. These studies, which were based on a strong foundation of core and log data, include most of the current wells in the field. Computerized databases associated with these early studies are no longer available, but the quality of the work was of sufficiently high quality to warrant rebuilding them from the hardcopies still available. This decision was achieved with the aid of a local consultant who, like staff of the Citronelle field operating units, had long experience with the field. Geological tops, along with what were judged by our experienced consultant to be the most reasonable past estimates of permeability, porosity, and water saturation have been entered for each sand in each well, along with other pertinent information, into a GeoGraphix database for subsequent display and analysis. Land grid and well location data were also obtained and entered into the system to provide modern mapping and cross section construction capabilities on a field-wide scale. Production data for the field were obtained from the state of Alabama and cumulative values at various points in time were extracted and put into the database also. Time and money were invested to assure that all data entered in the database were accurate. This database will constitute a constant basis for comparison through time and will become an important tool for implementing future reservoir management studies beyond the scope of the current study. The expenditure of resources in its construction is expected to prove exceptionally cost-effective over time.

As a first step in determining the best areas and approaches for obtaining additional recovery, cross sections in the areas of interest defined along the unit boundaries were used to define potential flow units as isolatable targets for improved recovery. These flow units were defined by combining into one package sands that are likely to be in vertical and horizontal communication with each other across the area of interest, but at the same time separated from adjoining sands or packages by substantial shale barriers. Due to past hydraulic fracturing practices in the field, a 30-ft minimum thickness was used to define effective shale barriers. As a next step toward identifying potential recovery targets, floodable OOIP volumetrics were calculated for each of the approximately 20 sand packages or flow units identified. Next, production and injection data and other data related to reservoir fluid flow were used to further segregate and rank those packages which had been less efficiently addressed by the current waterflood. Preliminary strategies for addressing recovery in the best ranked packages are developed as a next step. Flow units do not occur in isolation. Several flow units are commonly present in a single well, as well as numerous sands not identified as belonging to discrete flow units. A necessary next step, therefore, is to evaluate and strategize recovery for all sand packages and flow units involved in the well containing the flow units of prime interest. This final step assures that areas with the best recovery economics can be addressed first. In its refined form, this general methodology can then be applied throughout the field to maximize economic recovery from other sand packages.

## Conclusions

In designing, administering, and participating in the Department of Energy's Reservoir Management Demonstration Program, some useful new perspectives on reservoir management have been realized. The ideas are not necessarily new, nor are they particularly earth shaking, but taken together they do provide some guidelines in developing reservoir management approaches that are a practical fit to the reservoir and its context.

- Reservoir management is not an optional activity. Every reservoir must be managed in some way or other. Reservoir management is not just a term that refers to high-tech approaches to improving production in large reservoirs.
- The reservoir management plan is the concept central to reservoir management. It is the guide that governs the interaction of the operator with the reservoir. The process of reservoir management is simply the putting together of a

plan, following it, monitoring the reservoir's performance in terms of the plan, monitoring the technological and business assumptions on which the plan is based, and revising the plan as needed.

- Because many operators have been excessively risk averse in performing reservoir management, there is a great opportunity remaining to increase both profitability and production through appropriately designed reservoir management.
- Matching a reservoir management plan both to the reservoir and its larger context is critical to success and profitability. Designing an appropriate plan requires a knowledge of the reservoir system, including its rocks, fluids, wellbores, and surface facilities; a knowledge of the technologies available to describe, analyze, and exploit the reservoir; and a knowledge of the reservoir management business environment (both internal and external to the organization implementing the plan).
- A reservoir management plan cannot be taken or bought "off the shelf." It must be customized. The detailed steps in plan construction are being defined. Major steps (in addition to acquiring the necessary knowledges outlined above) include defining the amount and location of the target hydrocarbons, identifying the appropriate recovery technology and applying it optimally, optimizing operational procedures, and specifying criteria for plan revision.
- DOE's Reservoir Management Demonstration Program is pursuing further definition of the steps in plan development and, at the same time, is giving strong encouragement around the country for operators to use reservoir management techniques through participation in cost-shared research projects with heavy emphasis on technology transfer.

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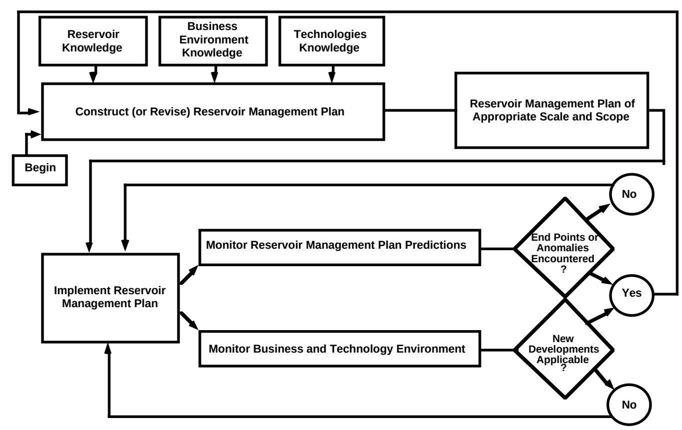


**Fig. 1— The reservoir management process is an iterative procedure involving plan construction (or revision), plan implementation, and monitoring the performance of the reservoir, technological advancement, and the reservoir management business environment.**

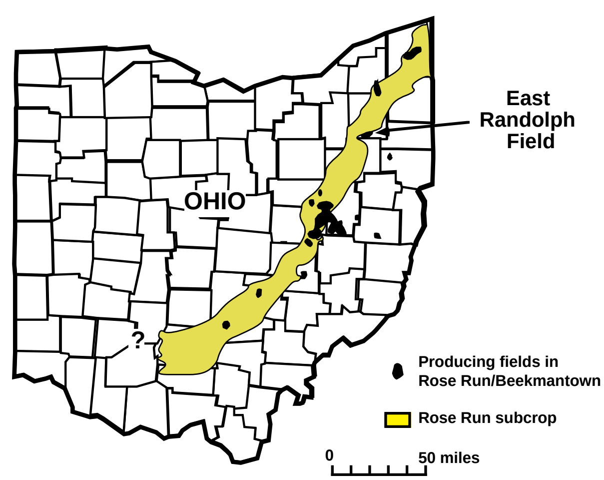


**Fig. 2—The East Randolph oil field is located in eastern Ohio in a northeast - southwest trend of reservoirs producing (mostly gas) from the Rose Run and the Beekmantown. (Modified version of Fig. 1 of Ref. 6.)**

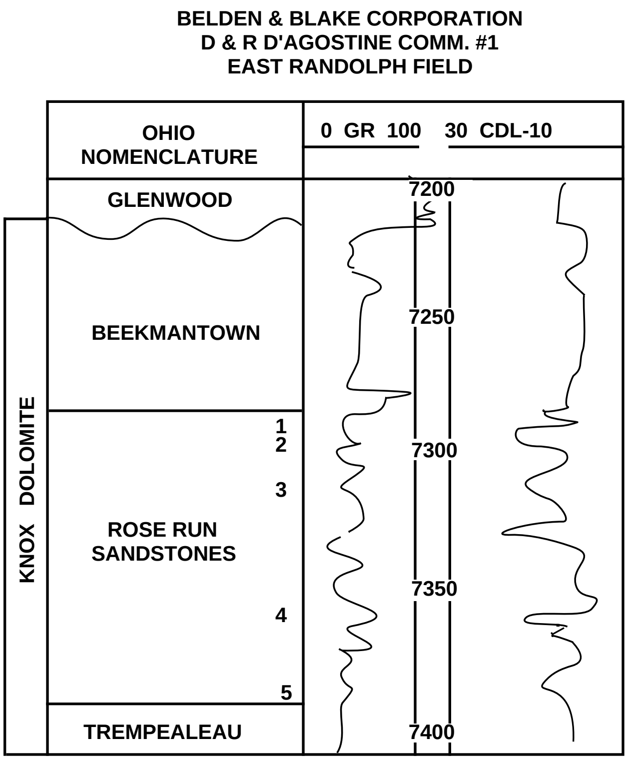


Fig. 3— This type log from the East Randolph field shows the five major sand zones of the Cambrian Rose Run Formation.

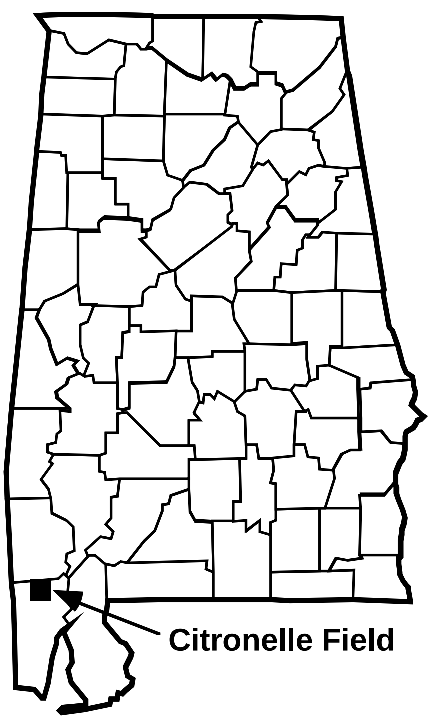


Fig. 4—Citronelle field is located on the eastern edge of the Mississippi Interior Salt Basin in northern Mobile County, Alabama.

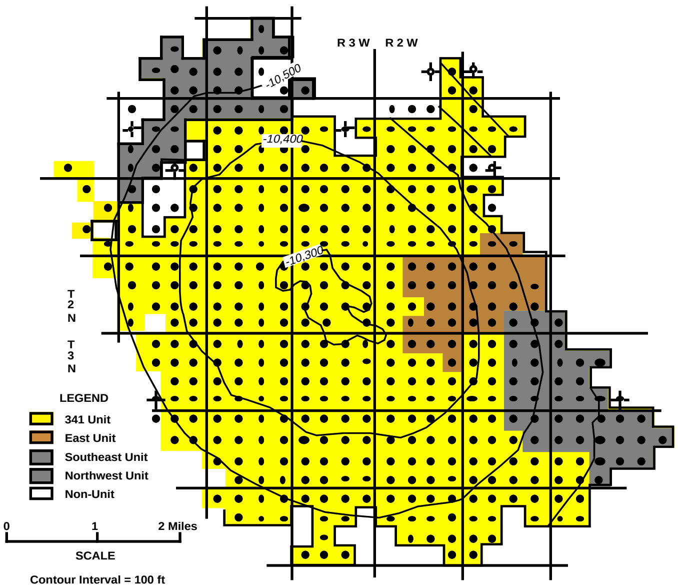


Fig. 5— This structure map of Citronelle field shows the location of the unit boundaries. These boundary areas are the primary focus of the current reservoir management study.